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Dear Heather

Locational pricing assessment – Call for input following first stakeholder session

We are pleased to respond to this call for input on your assessment of locational pricing. This response builds on the feedback we provided on 13 June on your proposed modelling approach, as set out in the slides of your 26 May stakeholder workshop. This response mainly reflects the views of our renewable generation business. We have responded in Annex 1 to the three requested areas for input, and would highlight the following points.

For reforms as fundamental and long-term as those under consideration, we believe it is most appropriate to focus on economic welfare (the sum of consumer and producer surplus) as the key measure of benefit, consistent with achieving over-arching objectives of meeting Net Zero targets and ensuring security of supply. These impacts should be identified and assessed separately from distributional impacts (eg those that involve transfers of between consumers and producers, such as reductions in constraint payments).

The range of opportunities identified by Ofgem to date appears to be influenced by the perspective of the ESO, which sponsored the original work from FTI Consulting. For example, the focus on growing constraint costs and the growing role of the balancing mechanism. We would encourage Ofgem to focus its assessment on areas where there are genuine opportunities for short and long run economic efficiency, including more efficient consumption (in particular with respect to flexibility), more efficient interconnector flows, more efficient dispatch and more efficient location decisions. Although these represent genuine opportunities in principle, we believe some are likely to be over-stated, measured relative to an inappropriate counterfactual, and with insufficient consideration given to real world limitations.

In respect of the counterfactual, it is essential that Ofgem gives full consideration to alternative reforms that don't involve locational pricing. Compared to status quo (which was not designed for the future energy system), it is unsurprising that gains can be identified with locational pricing. However, locational pricing will be hugely disruptive and other reforms (to TNUoS, to the balancing mechanism, to transmission capacity development processes, to the CM and CfD) may substantially deliver the benefits claimed for locational pricing without the attendant disruption and damage to investor confidence.

The key challenges associated with the introduction of locational pricing, should this be taken forward, will be to minimise the impact on investor confidence and uncertainty and hence the cost of capital; and to avoid disruption and hiatus to infrastructure development with knock-on impacts of achieving GB's decarbonation of the power sector and net zero targets. Realistic assumptions around implementation timelines will be relevant for mitigating these impacts. A further challenge in realising claimed benefits is that the location of demand and the best (and feasible) locations for generation that support a decarbonised electricity system are unlikely to be aligned and may therefore limit the extent to which locational price signals can drive more efficient geographic deployment (especially compared to a reformed TNUoS regime). To the extent that locational pricing does drive a different geographic pattern of generation and demand, it will be vital to minimise any consequent risks to long term system security and security of supply.

Finally, we welcome Ofgem's intention to involve a representative range of stakeholders and consult widely on its approach to modelling. For an assessment as far reaching as this it will be important to seek out and weigh up a range of competing views and approaches - including from different firms of economic advisers. It is also vital that the details of Ofgem's modelling (input assumptions and outputs) are published in sufficiently granular detail to allow informed assessment and critique by stakeholders.

Yours sincerely

Richard Sweet

Richard Sweet
Head of Regulatory Policy

<u>Annex 1</u>

LOCATIONAL PRICING ASSESSMENT – CALL FOR INPUT FOLLOWING FIRST STAKEHOLDER SESSION (26TH MAY 2022) – SCOTTISHPOWER RESPONSE

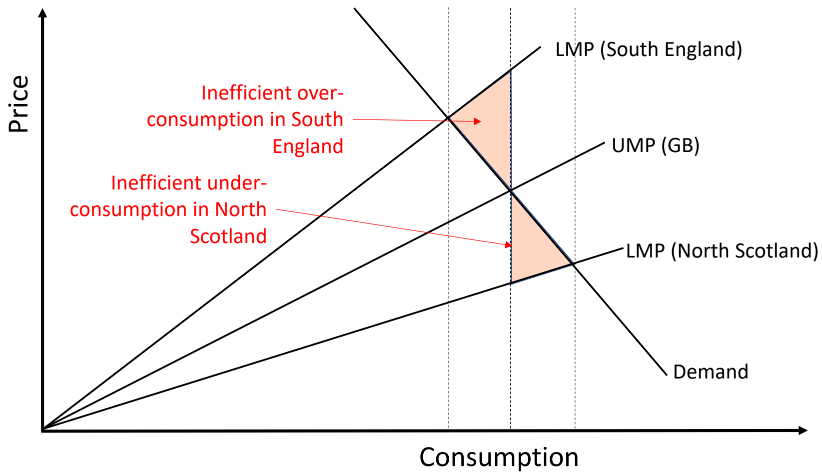
1. Key opportunities associated with introducing more granular locational pricing in GB

We set out below our views on where the key opportunities are likely to arise from more granular locational pricing and hence what should be the key areas of focus for Ofgem's proposed modelling. In our view, the narrative to date has been unduly influenced by the particular perspective of the NGESO, which commissioned much of the early assessment, and which emphasised the particular operational challenges it faces (growing constraint costs, greater role for balancing mechanism etc) rather than taking a more objective view of how the efficiency of the overall energy system can be improved. We set out below our view of the key short run and long run opportunities.

1.1. Short run opportunities

1. <u>More efficient consumption</u>

In our view, potentially the most significant opportunity from more granular locational pricing relates to more efficient consumption. Under uniform marginal pricing (UMP), the price may often exceed the marginal cost of electricity in North Scotland leading to inefficient under-consumption of electricity (i.e. social welfare would be higher if consumption was higher). Conversely, the UMP may often be less than the marginal cost of electricity in South England leading to inefficient over-consumption of electricity (i.e. social welfare would be higher if consumption was lower). This is illustrated schematically in the chart below.



Whilst many of the claimed benefits of locational pricing can be substantially replicated by reforms to other market mechanisms (such as TNUoS pricing), the efficiency (social welfare) gains from more accurate price signals for consumption cannot be replicated so easily. For this reason, we think it will be important to model this category of benefit in particular detail.

A key parameter in modelling these benefits will be the price elasticity of demand (the slope of the demand curve in the chart above). This will need to capture two different types of consumer response:

- time shifting of consumption in response to different intra-day (say) prices

- absolute changes in consumption in response to price signals.

For domestic consumers, previous work on locational pricing has generally assumed that *absolute* elasticity of demand is rather low (witness the small changes in consumption in response to recent wholesale market crisis); average prices may affect the extent to which consumers invest in more energy efficient appliances, but the sensitivity to energy prices is likely to be low. There is an expectation that *time shifting* elasticity may be somewhat higher, particularly as EV and electric heating penetration increases and technology makes it easier to respond. However, the question here will be how much *additiona*l benefit locational granularity can deliver over and above exposing consumers to time of use tariffs under UMP. There is also an important policy question as to whether it will be politically attractive to expose domestic consumers to regionally varying prices, or whether locational pricing may be accompanied by an equalisation mechanism for domestic energy supply.

For non-domestic consumers, the short-term elasticity of demand has also historically been assumed to be relatively low, though time shifting elasticity may be higher for the same reasons as for domestic. However, a key difference with the non-domestic segment is the possibility that new industrial processes such as green hydrogen production may exhibit higher elasticity. The economics of electrolysers are still being investigated, but it is reasonable to assume that the level of utilisation will be influenced to some extent by the relative prices of green hydrogen and input electricity.

2. <u>More efficient use of interconnectors to EU markets</u>

Another potentially important (but as yet unquantified) short term opportunity relates to interconnector flows. There is a risk that UMP may lead to inefficient flows of energy along interconnectors with the result that interconnector flows actually aggravate constraints. For example, if the UMP in South England is lower than the LMP, this may cause power to be exported to France when in fact it would be more efficient to be importing. And *vice versa* for flows between Scotland and Norway. This is another potential efficiency gain for locational pricing which cannot easily be achieved by other mechanisms. However, a key issue for any quantitative assessment of benefits will be to model how frequently and severely such perverse price signals will actually arise (and have actually arisen) in practice.

3. <u>More efficient dispatch of generation and storage</u>

A third category of short term opportunity is more efficient dispatch of generation and storage. If we focus on economic efficiency, the benefits arise when a lower cost generator is dispatched than would be the case under UMP and BM. (Ie, ignoring any impact on constraint payments which is essentially a wealth transfer mechanism rather than efficiency saving). For example, it has been suggested that a central dispatch model could optimise dispatch over multiple sequential time periods and better take account of the costs of ramping up and ramping down thermal generation plant (or indeed nuclear) and the physics of the transmission grid.

Key questions here will be the materiality of such efficiency gains and the extent to which they could be replicated by use of more sophisticated optimisation systems in the BM including dynamic scheduling and improved dispatch of connected storage. (Given the substantial level of investment envisaged for central dispatch systems in locational pricing, it would be wrong not to consider what could be achieved instead by investment in existing BM systems, which are currently playing a much greater role than was originally envisaged for the BM.)

4. Constraint payments

Much has been made by NGESO of the opportunity afforded by locational pricing to reduce constraint payments (which it forecasts will continue to increase) and hence to reduce BSUoS costs in consumer bills. This a different (and inferior) category of 'benefit' from those identified above, and should be given less weight than it appears to be receiving at present.

Constraint payments are a transfer not a matter of efficiency, and reducing constraint payments will not enhance social welfare. Ofgem should certainly consider impacts on constraint payments as part of the distributional analysis, but it would be wrong to consider reducing constraint costs as an efficiency benefit. In this context we would note that:

- One reason for a high level of constraint payments is delays in building out new transmission capacity. This is much more effectively dealt with by reforming processes to enable faster (or more anticipatory) network deployment.
- Increasing levels of constraint payments are not bad *per se*, but rather indicate that the system is working as intended: it would be inefficient to size the network so that wind was never constrained off; if renewables penetration is increasing, so should the efficient volume of constraint payments.
- Because constraint payments represent a transfer between producers and consumers, any change is likely to be compensated over time by transfers in the opposite direction; e.g. renewables developers may receive more from the CfD mechanism. (Indeed, the uncertainty and loss of investor confidence caused by introduction of locational pricing could lead to less efficient outcomes.)
- Net Zero market reform creating more opportunities for ancillary services markets including but not limited to stability market, reserve, frequency response and constraint management pathfinders, should ultimately drive down system balancing costs as they will reduce dependency on conventional generation providing bulk of these services.

Similar observations can be made about claimed reductions in aggregate consumer bills. If the reduction in consumer bills stems from a more efficient overall system, that is a valid and worthwhile benefit. If the reduction in bills results from a transfer between producers and consumers, that is a much more questionable and less sustainable benefit.

1.2. Long-run opportunities

5. Efficient location of generation and storage (and demand)

NGESO has suggested that locational pricing could provide more accurate signals for the location of future generation and storage investment.

Currently generation and demand are both exposed to locational pricing signals via TNUoS charging. These signals may be suboptimal at present, but there is work under way to reform TNUoS, and it is reasonable to assume that more efficient locational price signals could be achieved in future, which accurately reflect the impact of different locations on transmission costs.

The key difference between these two types of price signal is that TNUoS charges are typically based on capacity connected (MW) and do not vary from day to day or hour to hour; price signals via locational pricing, in contrast, would be linked to output (MWh) can vary dynamically. However, we are not aware of any evidence that this would make a material difference in practice to the efficiency of location decisions.

A related concern with locational pricing is the potential unpredictability and volatility of the locational price signals. Similar concerns have been raised with TNUoS, and reducing them will be one of the key objectives of TNUoS reform, but in our view the uncertainty and volatility of the locational pricing price signal could be even worse than for TNUoS. Even if there is a theoretical/statistical gain to be had from the locational price signal, it may be outweighed by these other factors.

Similar considerations could in principle arise with demand, but in general demand will be less flexible in location than generation, and will potentially also be influenced by TNUoS charging.

Although such benefits are possible in theory, we believe Ofgem should be highly sceptical in the absence of robust evidence.

6. Efficient mix of energy resources

As well as driving a more efficient spatial distribution of generation and demand, more granular locational pricing could in theory lead to a more efficient mix of energy resources. For example, if nodal pricing led to certain nodes having much greater temporal variation in prices than would be observed under UMP, this could provide a positive signal for investment in storage or other technologies that can exploit the arbitrage opportunity. The materiality of such benefits would need to be investigated before significant weight is given to them.

1.3. Assessing opportunities

Given the potential uncertainty and disruption around the implementation of locational pricing, we welcome Ofgem's intention to undertake further rigorous and quantitative analysis to better understand the potential benefits, including the scale of benefits and the distributional impacts.

Our current view is that the scale of benefits from introducing locational pricing may be relatively modest, at least when compared to an enhanced status quo, and is unlikely to outweigh the costs resulting from the risks and challenges that we set out in response to Question 2.

Given the huge potential impact of any decision to introduce locational pricing - on energy costs and resilience and achievement of net zero – it is important that Ofgem brings in a wide range of independent experts to assist in its modelling. Whilst we can understand why Ofgem may have chosen to use the same consultants as used by NGESO, and we have no reason to doubt their independence and impartiality, we believe it would be healthy for Ofgem to commission modelling and analysis from other firms who could bring new insights and mindsets to the work.

1.4. Alternative options

We also consider that many of the claimed benefits and opportunities from locational pricing could be achieved through alternative, less disruptive and costly, reforms. For instance, through reforms to BSUoS and TNUoS. Consideration could be made to how the Balancing Mechanism (and wider markets) could better enable the most efficient redispatch following gate closure, for example, by increasing the period between gate closure and delivery.

Supporting network investment so that the network keeps pace with generation expansion is also key to bring down constraint costs, as demonstrated by NG ESO's own analysis of constraints. If the issue policy makers are seeking to solve is improved signals to unlock potential sources of flexibility and demand response, then this may also be supported through improved long term investor certainty, for instance, through changes to the Capacity Market or longer term ancillary service contracts.

2. The key implementation challenges, risks and mitigations

We have identified multiple issues and challenges with introducing locational pricing, which we set out below.

2.1. Supply

2.1.1. Impact on investment and cost of capital, which could set back progress to reaching renewable generation capacity targets, a decarbonised electricity system and net zero.

There is significant concern amongst industry that locational pricing would disadvantage renewable generation, especially offshore wind and that the associated uncertainty would lead to a higher cost of capital. Not only would constraint payments be removed and wholesale prices lower in low demand areas, but dispatch would also be affected, which impacts CfD plant even though they have the agreed strike prices.

Progressing locational pricing would bring significant revenue uncertainty across the market for several years during a period when it is essential for the UK to deploy new electricity generation capacity at an unprecedented pace and scale to reach Net Zero.

Under a nodal model, there would be multiple complex and evolving factors that would influence price in a particular location. Investment cases to financiers currently rely on projected forward curves, which will be significantly more challenging to model with reliable assumptions at a nodal level. Self-dispatch currently allows generators to determine when they access the market, which also provides investors with greater revenue certainty than a central dispatch model. Limiting revenue uncertainty is vital for investor confidence.

2.1.2. The rationale for locational pricing ignores wider location considerations that determine what capacity is possible to build where

There are multiple reasons why it is difficult to build generation close to demand: planning policy, higher land value, unavailability of land, lack of suitable geographic/weather conditions (relevant for e.g. pumped hydro, solar and wind), greater disruption to communities and political/local opposition to certain capacity technologies (for instance, nuclear) close to populations.

There is therefore a risk that modelling of locational pricing will come up with spuriously high benefits associated with generation capacity moving to locations which in practice would not be possible for the reasons mentioned above. It is essential that the modelling approach takes these issues into account and that if the final assessment relies on this type of benefit, it is given thorough scrutiny. (In our view, it seems likely that new generation capacity will largely be built in the same locations as without locational pricing, but possibly in smaller volumes if the financial case for investment will be less attractive.)

2.1.3. Implications for system security and security of supply

Power flows in the GB system over the last 5 years have shown significant variations, where interconnectors across England and Scotland have witnessed far more instances of two-way power flow. Hence, reinforcing the point that there is no specific pattern to spatial allocation of demand and generation, especially in case of vast amounts of renewable generation connected to the network. The variation of generation and demand throughout the day across GB is supported by an interconnected transmission network that ensures security and reliability of power supply.

In recent NOA assessments, significant network reinforcements have been identified as necessary in Scotland, both in SSEN and SPEN networks. These assessments show the need for a robust transmission grid and significant investments will be made over the next decade to strengthen the Scottish transmission network to support 30+ GW of offshore generation. This, along with the holistic network design (HND) process, could potentially establish an offshore grid, which operates parallel to the onshore grid with multi terminal connections to the onshore network. There are also plans to create an interconnected HVDC grid in the north of Scotland. In the context of these significant network changes, it will be important to be alive to any possible unintended consequences on security of supply from locational pricing.

The GB system operation and security of supply is a multi-dimensional problem with increasingly dynamic behaviour. Locational pricing may not incentivise adequate development of the transmission network, and necessary services provisions as it does not take system security and operability assessment into consideration. For example, locational pricing could drive more generation to be connected in England and Wales, without consideration to security of supply to low demand customers in low population areas such north of Scotland, as it attempts to solve the one-dimensional problem of constraints. This would be at odds with GB's high expectations for reliability of power supply to all customers (historically GB's reliability has been 99.9%[1]), which has driven most network investments.

The experiences of Texas ERCOT provide a good example of how nodal pricing was introduced to help cope with limited network infrastructure, but these conditions risked system and supply security and resulted in a system unable to handle extreme demand peaks and load shedding[2]. The Texas freeze of February 2021 left more than 4.5 million households (over 10 million people) without electricity, some for several days. Economic losses from lost output and damage were estimated to be $130 billion. The state faced outages of 30 GW of electricity as demand reached unprecedented highs and forced ERCOT, the grid manager, to cut off supply to millions of customers or face a system collapse. Operation of its own independent market in Texas based on nodal pricing, led to less interconnection requirements between nodes and across state boundaries as it affects its own market operations. The 2021 freeze suggested a need to rethink the state's regulatory approach to energy, with a focus on weatherization, demand response, and expanded interstate interconnections.

2.1.4. The removal of constraint costs will appear in other places

As noted in section 1, the benefits of reduced constraint payments under locational pricing should be treated with scepticism as any cost savings are likely to be offset by other changes. For example, where generators lose revenue from existing constraint payments and reduced dispatch, they will likely need to charge more per unit of energy to make the

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[1] https://www.nationalgrideso.com/news/how-does-eso-manage-periods-low-demand

[2] Cascading risks: Understanding the 2021 winter blackout in Texas - ScienceDirect

same return, so prices are likely to increase in other markets. One likely impact would be increased strike price bids from projects bidding for CfDs.

Ofgem says in its note of the first workshop that FTI's modelling approach intends to calculate the impact of zonal and/or nodal designs on the CfD top-up payments (ie, the increased or decreased quantum of support that may be required as a result of the wholesale power price changes), but this is only part of the picture and fails to take account of impacts on RO-supported or merchant generation. Instead, we believe the impact on constraint payments should be disregarded in terms of the benefits assessment and considered only as part of the distributional analysis.

2.1.5. Reduced renewable dispatch could lead to shortened lifetime of existing capacity

Generation that was built in a location with consideration to existing market mechanisms, as discussed above, may receive reduced revenue under locational pricing, especially renewables located in low demand areas. If they are not able to replace this lost revenue, such assets will be less likely to refurbish to extend site lifetime or repower and some may even decommission if revenues are insufficient. This means that alternative generation may need to be built instead, with additional capex, to replace potential stranded assets. These costs should be considered as part of any modelling.

2.1.6. Disruption and implementation costs

In addition to disrupting investment, locational pricing would have significant implications for the design and regulation of the whole electricity system, and will further increase complexity. There are likely to be significant additional implementation costs with creating new systems for market operation, settlements, code revisions and project management. Ofgem should also consider the potential need for grandfathering costs. Market participants will also require significant IT and process change programmes. We would also highlight that the electricity sector does not have a good record a delivering new IT systems. Creating additional complexity is also likely to create additional barriers to entry to the power market and harm competition, which would also limit downward pressure on consumer bills.

2.1.7. Market power and liquidity issues

Locational pricing will give rise to increased competition risks because it will mean fewer competitors participating in many local markets, relative to the many competitors in a single national market. This brings the opportunity for market power and gaming/price manipulation by some players (primarily generators but also potentially large sources of demand) who have a material presence around some nodes.

We also anticipate that the reduced liquidity associated with locational pricing would make forward hedging even more challenging for retailers (which is important for suppliers seeking to match against the price cap regime), in the context of some suppliers already finding it challenging to find sufficient capacity to buy in forward markets.

2.1.8. Financial Transmission Rights uncertainties and challenges

In their Net Zero Market Reform project, the ESO say that the revenue uncertainty that market participants would be exposed to in a nodal locational pricing market could be partially hedged through financial instruments, principally Financial Transmission Rights (FTRs). The extent to which a FTR market could be effectively established and mitigate revenue uncertainty is unclear and assessments of locational pricing should not simply assume that FTRs will resolve uncertainties or lead to less uncertainty (as the ESO appears to have in their assessment) than the status quo, or the market conditions following any reforms resulting from the TNUoS Task Force.

2.1.9. Zonal pricing issues

As the ESO acknowledge, there would be additional challenges and weaker potential benefits from introducing zonal pricing. The ESO does not consider that zonal pricing would deliver efficient location signals. It would also not be suited to a central dispatch model, without which a balancing mechanism would likely remain. For zonal pricing to accurately reflect network constraints, zone boundaries would need to be granular and adaptable to changes in congestion dynamics, which the ESO say "would be highly challenging to achieve and would add significant regulatory risk to market participants", as has been the case in Italy, Germany, Austria and Sweden[3]. The ESO also considers that the uncertainties around changing zonal boundaries would expose the market to significant regulatory risk, which could not be hedged against through FTRs, resulting in weaker investor confidence that the status quo.

2.2. Demand

2.2.1. Impact of uncertainty

A key issue in modelling short-run efficiency impacts will be correctly factoring in the extent to which uncertainty in future pricing limits the efficiency of intertemporal arbitrage by consumers or generators with flexibility. As an example, if locational marginal prices are set on a real time basis, then a customer choosing when to charge an electric vehicle will need to predict the future pattern of prices in order to decide when to charge. If the predicted pattern of prices is wrong, then the selected charging profile will be inefficient. Given the potential nature of future price patterns, with prices fluctuating between very low and very high and being driven by wind volatility, imperfect price forecasting could have a material impact on the ability of consumers to fully leverage locational pricing price signals.

2.2.2. Demand has limited flexibility and mobility to respond in the long run

As noted in section 1.2, a potential long run benefit of locational pricing relates to network cost savings from supply moving closer to demand and/or demand moving closer to supply. However, there is limited evidence to suggest that locational pricing would result in non-domestic consumers changing location just to reduce energy costs. Relocating is expensive and creates disruption for employees. A business may lose employees who are unwilling to relocate and may need rehire in the new location, and there a various considerations for new locations besides energy cost – labour supply/skills, infrastructure and wider local services. Encouraging firms to relocate to reduce their energy costs could bring negative externalities - stranded assets and services (eg. schools and hospitals) and wider social problems.

Given the complexities of estimating long-term price-elasticity of industry siting decisions (and the key role of other factors, rather than just wholesale electricity prices), Ofgem suggests it will be most appropriate to treat demand portability as an exogenous sensitivity, which should help in understanding the potential system impacts of sources of demand changing their siting decisions in response to differing wholesale price signals. We agree that it is worth considering, but, with a few possible exceptions (such as hydrogen electrolysis) we do not see demand relocation as being a material consideration.

[3] Net Zero Market Reform May 2022, Phase 3 Assessment and Conclusions, Page 5 and 37.

2.2.3. Politicising supply and grid connections

By exposing either domestic or non-domestic consumers to locational pricing, there will be new parties who will be interested in reducing their local price nominally, but also relative to other UK locations. It is therefore likely that lobby groups would form. A community that encounters low prices may seek to limit network capacity increases and new grid connections in their area, which may also slow net zero progress.

2.2.4. Regional disparities in cost

Exposing domestic consumers to locational pricing could be perceived as unfair and could be highly controversial, not least because it would increase energy bills for millions of households. Time of use pricing may be perceived as unfair by those who are unable to shift their consumption but at least there is a clear narrative around optimal use of EV charging infrastructure etc. For locational pricing there are no such opportunities, and an (incorrect) perception could arise that the Government or Ofgem is seeking to encourage people to move away from high demand and low supply locations and punishing inflexible people who happen to have situated their lives in higher cost locations.

Given the demographics of urban areas, the Government and Ofgem are also likely to find that the cost increases would be most heavily felt by people with protected characteristics under the Equality Act 2010. Any Ofgem or Government assessment of location pricing should, to meet their Public Sector Equality Duty, assess and consider the impacts on these groups.

2.2.5. Implications from not exposing domestic consumers to locational pricing

Given the sensitives with exposing domestic consumers to locational pricing, it is possible that the Government and/or Ofgem will decide to create a means of averaging variations in wholesale prices across the UK. However, this would remove some of the potential efficiency benefits from more efficient consumption, and as a result there could be distortions to investment decisions between generation and demand.

We also consider that such a decision would bring its own political challenges. Low demand and high supply areas, such as the devolved administrations, would be getting the worse of both design choices – decreased wholesale revenue for generation in the region and likely reduced or cancelled future renewable generation investment; and no reduction in price. Ofgem and the Government may wish to consider the risks that such an outcome/future prospect could bring for the continued union of the UK.

2.3. Comparisons with other countries

We have noted that a common argument for locational pricing is that other countries have adopted it and have not yet chosen to reverse this decision and/or that the introduction has been successful. However, we have not seen detailed analysis presented or referenced that supports the case that introductions have been successful, and we believe further analysis is needed in this space. We also consider that, whilst lessons should be learnt from other jurisdictions, there will also be local factors that limit the extent to which findings from one country can be extrapolated to another. For instance, Texas ERCOT, has very different system framework to the UK and, as noted in 2.1.3, is poorly connected to its neighbouring regions.

3. The proposed approach to modelling zonal and nodal market designs

We provided detailed feedback on the modelling approach proposed in our letter of 13 June 2022[4] in which we offered two key observations on the approach to modelling:

3.1 Economic efficiency versus consumer bill impact

Ofgem says the objective of the modelling is to assess the potential benefits, costs and distributional impacts associated with locational pricing options (slide 9) but does not specify how the benefits will be measured.

For reforms as fundamental and long-term as those under consideration, we believe it is most appropriate to focus on economic welfare (the sum of consumer and producer surplus) as the key measure of benefit, consistent with achieving over-arching objectives of meeting Net Zero targets and ensuring security of supply. This approach has been widely used in academic assessments of locational pricing[5,6,7,8], and is the best measure of economic efficiency.

It may also be helpful to model consumer bill impacts, as part of the assessment of distributional impacts, but estimates of distributional impacts are generally less robust in the longer run, given the relative ease with which benefits can be reallocated/transferred between market participants. In contrast, economic efficiency is more challenging to achieve and should be the principal goal of market reform.

As a minimum, Ofgem should model both measures separately and avoid conflating the two.

3.2 Counterfactual should be enhanced version of status quo

Transitioning to locational pricing will be hugely disruptive and expensive and the benefits of doing so should be compared against an appropriate counterfactual which reflects the opportunities to improve existing arrangements (short of moving to locational pricing), not against the current status quo. These evolutionary improvements should include *inter alia*:

- Reforming TNUoS: current ICRP-based network charges are known to suffer from significant problems including unpredictability, volatility and inaccurate locational pricing signals (misaligned with NOA assessment and actual investment)

- Optimal transmission network investment: the modelling should take care to avoid inflating the assessment of benefits as a result of assuming suboptimal levels of network investment – as may currently be the case due to project delays; such

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[4] Locational pricing modelling approach – ScottishPower feedback 13.6.22
[5] Green, R. J. (2007). Nodal pricing of electricity: how much does it cost to get it wrong? *Journal of Regulatory Economics*, *31*(2), 125-149. doi:10.1007/s11149-006-9019-3
[6] Leuthold, F., Rumiantseva, I., Weigt, H., and Jeske, T. (2005). Nodal Pricing in the German Electricity Sector - A Welfare Economics Analysis, with Particular Reference to Implementing Offshore Wind Capacities. Dresden. http://tu-dresden.de/die_tu_dresden/fakultaeten/fakultaet_wirtschaftswissenschaften/bwl/ee2/dateien/ordner_publikationen/wp_ge_08_dietrich_hennemeier_hetzel_et al_nodal_pricing_germany.pdf
[7] Leuthold, F., Weigt, H., and Vonhirschhausen, C. (2008). Efficient pricing for European electricity networks – The theory of nodal pricing applied to feeding-in wind in Germany. *Utilities Policy*, *16*(4), 284-291. Elsevier Ltd. doi:10.1016/j.jup.2007.12.003
[8] Di Castelnuovo, M. (2010). *Optimal spatial pricing for electricity and its impact on renewable generation technologies and their operations*. Imperial College. www.florence-school.eu/.../Publications Matteo di Castelnuovo. pdf

benefits could be achieved by alternative means such as facilitating more timely capacity enhancement.

- Enhanced systems for balancing: NG ESO has highlighted that its activities in the balancing mechanism are far more extensive than originally intended and could lead to suboptimal dispatch; given that a move to locational pricing will require investment in ambitious new modelling and optimisation systems for central dispatch, it would be wrong to disregard the potential to make similar investment in the systems used for balancing and/or reform the current processes (e.g. timing of gate closure etc).

- Optimal siting of generation assets: if it can be shown (e.g. through the modelling which is being proposed) that current support mechanisms such as CM and CfD will result in suboptimal siting of generation assets, even after reform of TNUoS (e.g. too many wind farms in Scotland rather than England), it may be simpler and less disruptive to adjust the relevant mechanisms to include an appropriate spatial capacity and constraints signal.

These enhancements should either be built into the counterfactual from the start, or Ofgem should make explicit provision from the start to model them within the proposed sensitivity analysis.

In addition to the specific feedback provided in our letter of 13 June, we have the additional feedback on 26 May workshop materials:

3.3 Modelling Approach

<u>Impacts</u>

The modelling should assess the expected impact on renewable generation investment (including the Scotwind projects) and implications for meeting the Government's decarbonising the power sector by the 2030s commitment and wider net zero commitment, as introducing locational pricing may set back total renewable capacity and deployment. As part of this assessment, the mobility/ability of generation to locate in efficient locations should also be considered, including external factors that may impact this such as: land value/rent and availability that provide suitable geographic/weather conditions (relevant for e.g. pumped hydro, solar and wind), planning policy and political/local opposition to certain capacity technologies being built and operating close to demand. It is also important to consider that developing assets in sub-optimal locations is likely to limit yield, and/or increase costs of construction, leading to an overall increase in costs of the electricity produced.

<u>Stakeholders</u>

As part of the customer impact, the assessment must consider two outcomes based on whether customers will or will not be exposed to locational price differences. This is particularly important for inflexible customers who are unable to respond to price signals or unable to relocate as the impact will differ depending on their exposure to locational price differences.

It will be important (particularly for distributional impacts) to model some of the categories with greater granularity than implied in Ofgem's workshop slides. For example 'consumers' should be subdivided into:

- Domestic consumers

- SME
- Industrial and commercial (I&C)
- Energy intensive industry (EII)

We would suggest that hydrogen electrolysers should be considered as a separate category of demand, distinct from storage/ICs and EII.

Ofgem should provide more detail on how it proposes to model the elasticity of demand for different categories of consumer. This should include time shifting of consumption and absolute increases/decreases in consumption in response to price changes. This will be an essential input to modelling of consumer surplus and the extent to which locational pricing can lead to greater economic efficiency

Scenarios

Ofgem is proposing to base the modelling on the 'Leading the way' and 'System Transformation' scenarios. We agree that System Transformation should be included to reflect the low end of the range of constraint costs. However, we believe 'Consumer Transformation' would be a more prudent/realistic scenario than 'Leading the way' to capture the higher end of constraint costs.

System operability

The System Operability Framework must be built into the assessment and detailed technical studies need to be performed to ensure that implementing locational pricing will not result in poor power quality, reliability and security for low demand areas. A new draft system operability framework for implementing nodal pricing at different nodes will be useful to analyse the need for system services at different nodes. We consider that there is a risk locational pricing will lead to frequent instability issues between different nodes and at nodes with low demand. System security, system stability and resilience of supply cannot be compromised with implementation of locational pricing.

Implementation of Holistic Network Design and offshore grid should help alleviate the challenges with constraints within the GB network. As 50 GW of generation is the target for offshore connection, use of a meshed grid and a multi terminal approach to effectively manage network capacity issues and maintaining the flexibility to transfer power to and from East and West to Scotland and *vice versa*, may prove to be a more effective and sustainable strategy.

Efficient and dynamic dispatch modelling of connected storage on GB network has not been considered in the current analysis. It is prudent to first consider how efficient scheduling and dispatch of vast amounts of connected storage on GB network could help with efficient management of constraints.

3.4 Key assumptions

Approach to CfD contract holders

The impacts of central dispatch must be considered as this could reduce renewable dispatch and therefore the revenue of CfD-supported plant. There may also be regional differences in outcome, which should also be assessed.

Security of supply impacts

Potential impacts on security of supply under locational pricing should be considered within the sensitivity analysis. With all development for generation being considered around clusters of demand, the impact on the security of supply of low demand areas during system events, black out or periods of low generation must be included.

Impacts on system stability under locational pricing should also be considered. Nodal developments may lead to more fluctuations in frequency in different regions, leading to more system islanding. Regional stability must be considered in islanded modes.

3.5 Potential policy impacts and interactions

Other

The assessment must consider the transmission investment required to bring offshore generation to demand centres.

ScottishPower
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